Fourth Quarter & Full-Year 2017 Results

Approach Resources Inc.

MARCH 9, 2018

Forward-looking statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of management regarding plans, strategies, objectives, anticipated financial and operating results of the Company, including as to the Company's Wolfcamp shale resource play, estimated resource potential and recoverability of the oil and gas, estimated reserves and drilling locations, capital expenditures, typical well results and well profiles, type curve, and production and operating expenses guidance included in the presentation. These statements are based on certain assumptions made by the Company based on management's experience and technical analyses, current conditions, anticipated future developments and other factors believed to be appropriate and believed to be reasonable by management. When used in this presentation, the words "will," "potential," "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," "target," "profile," "model" or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. In particular, careful consideration should be given to the cautionary statements and risk factors described in the Company's most recent Annual Report on Form 10-K and Quarterly Reports on Form 10-Q. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Cautionary statements regarding oil & gas quantities

The Securities and Exchange Commission ("SEC") permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. The Company uses the terms "estimated ultimate recovery" or ("EUR"), reserve or resource "potential," and other descriptions of volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's rules may prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized by the Company.

EUR estimates, identified drilling locations and resource potential estimates have not been risked by the Company. Actual locations drilled and quantities that may be ultimately recovered from the Company's interest may differ substantially from the Company's estimates. There is no commitment by the Company to drill all of the drilling locations that have been attributed these quantities. Factors affecting ultimate recovery include the scope of the Company's drilling project, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling and completion services and equipment, drilling results, lease expirations, regulatory approval and actual drilling results, as well as geological and mechanical factors. Estimates of unproved reserves, type/decline curves, per well EUR and resource potential may change significantly as development of the Company's oil and gas assets provides additional data.

Type/decline curves, estimated EURs, resource potential, recovery factors and well costs represent Company estimates based on evaluation of petrophysical analysis, core data and well logs, well performance from limited drilling and recompletion results and seismic data, and have not been reviewed by independent engineers. These are presented as hypothetical recoveries if assumptions and estimates regarding recoverable hydrocarbons, recovery factors and costs prove correct. The Company has limited production experience with this project, and accordingly, such estimates may change significantly as results from more wells are evaluated. Estimates of resource potential and EURs do not constitute reserves, but constitute estimates of contingent resources which the SEC has determined are too speculative to include in SEC filings. Unless otherwise noted, internal rate of return ("IRR") estimates are before taxes and assume New York Mercantile Exchange ("NYMEX") forward-curve oil and gas pricing and Company-generated EUR and decline curve estimates based on Company drilling and completion cost estimates that do not include land, seismic or general and administrative ("G&A") costs.

Solid foundation for long-term value

APPROACH RESOURCES OVERVIEW

Enterprise value \$656 MM[1]

High-quality reserve base

- 181.5 MMBoe proved reserves[2]
- 60% liquids, 28% oil
- \$582.2 MM PV-10 (non-GAAP) at NYMEX strip[3]

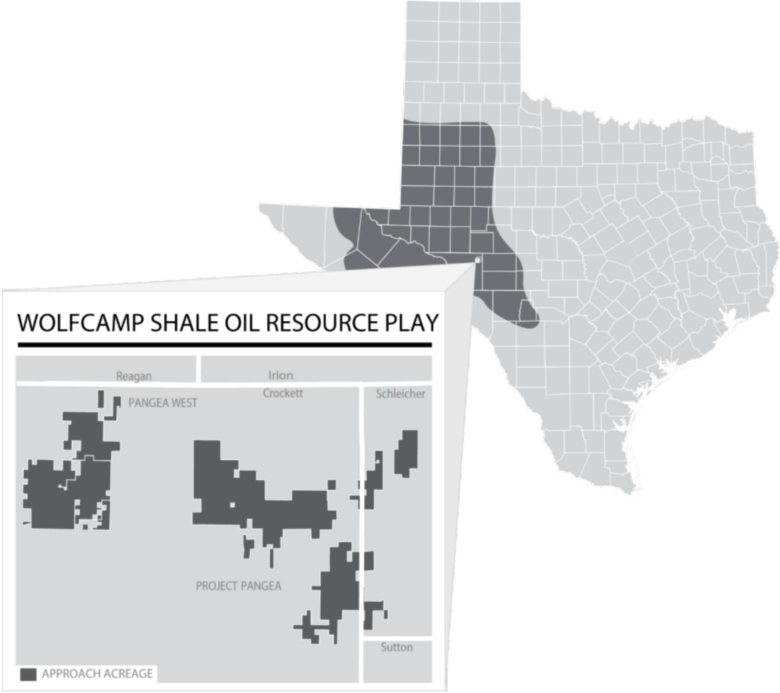
Permian Basin core operating area

- 165,000 gross (149,000 net) acres
- ~1 BnBoe gross, unrisked resource potential
- ~1,350 identified HZ drilling locations
- ~100% working interest
- Large contiguous acreage position with multiple benches
- Prolific Wolfcamp shale is the largest estimate of unconventional oil ever assessed by USGS[4]

Capital program focused on aligning capex with cash flow

- Stable leasehold that is largely HBP provides for flexible budget
- Improving commodity prices would allow us to seamlessly increase capital budget, funded with operating cash flow
- Drilled 13 horizontal wells and completed 9 through YE17, ended 2017 with 10 DUCS

ASSET OVERVIEW



1. Enterprise value is equal to market capitalization using net debt, the closing share price of \$2.96 per share and the share count each as of 12/31/2017
2. Proved reserves and acreage as of 12/31/2017. All Boe and Mcfe calculations are based on a 6 to 1 conversion ratio. Reserves were estimated using SEC pricing at December 31, 2017 and were calculated based on the first-of-the-month, twelve month average prices for oil, NGLs and natural gas of \$51.34 per BBL, \$18.67 per Bbl and \$2.99 per MMBtu, respectively, adjusted for basis differentials, grade and quality.
3. See slide 23 for our reconciliation of PV-10 using SEC pricing to the Standardized Measure of Discounted Future Net Cash Flows, and the NYMEX strip pricing as of December 31, 2017.
4. Per USGS estimates - https://www.usgs.gov/news/usgs-estimates-20-billion-barrels-oil-texas-wolfcamp-shale-formation.

Recent catalysts and execution focused on value creation - provide momentum in 2018 and beyond

GenX frac design driving well performance, type curve increased 37% to 700 MBoe

Increased YE 2017 proved reserves by 16%

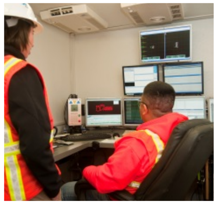
Extension of credit agreement to 2020

Shallow PDP decline and low operating cost generate meaningful cash flow for operations

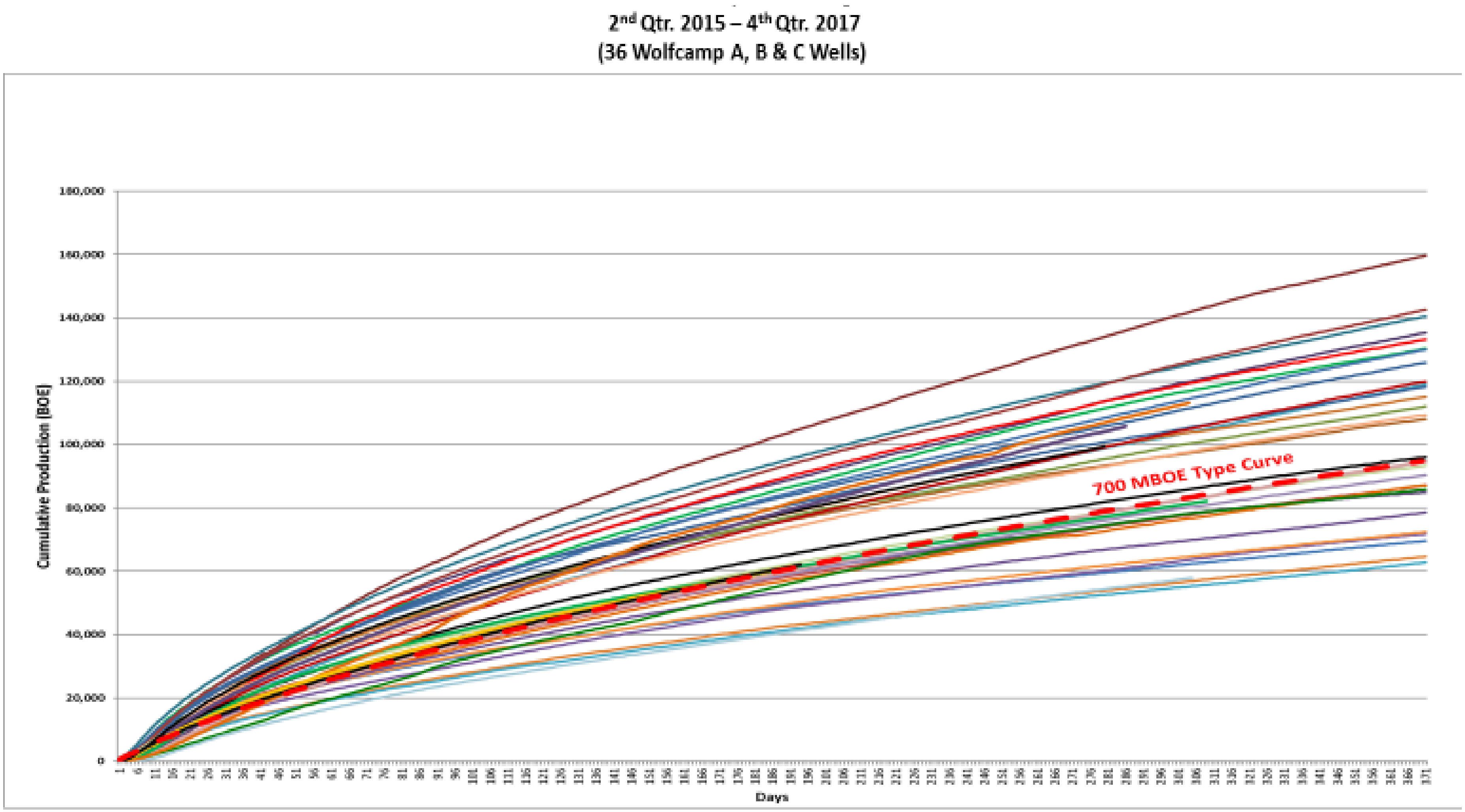
Disciplined hedging program manages risk while providing substantial upside

Majority of acreage HBP, enabling focused development near infrastructure mitigating OFS escalation

Water Treatment System

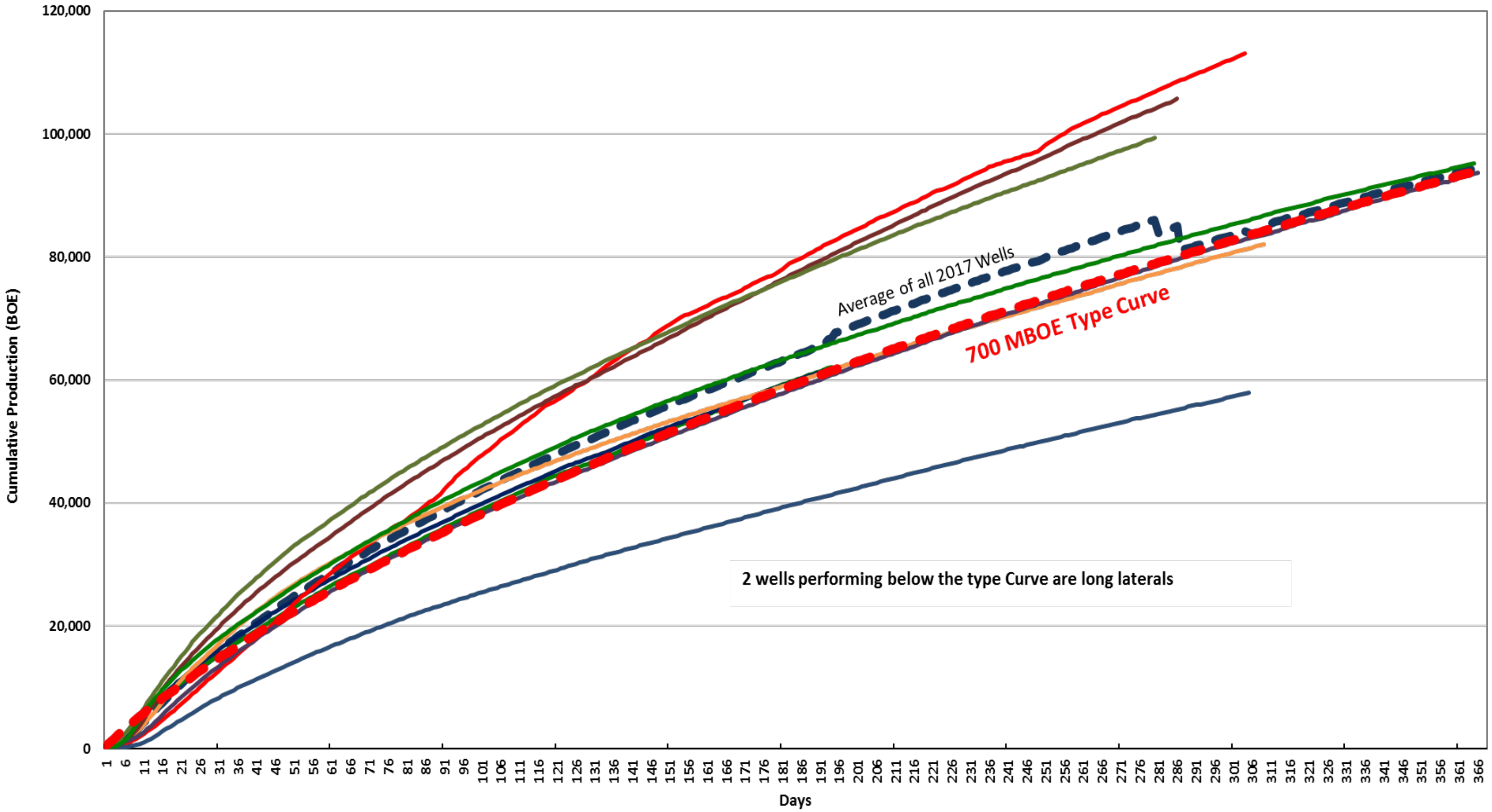


GenX frac design driving well performance, new AREX type curve 700 MBoe



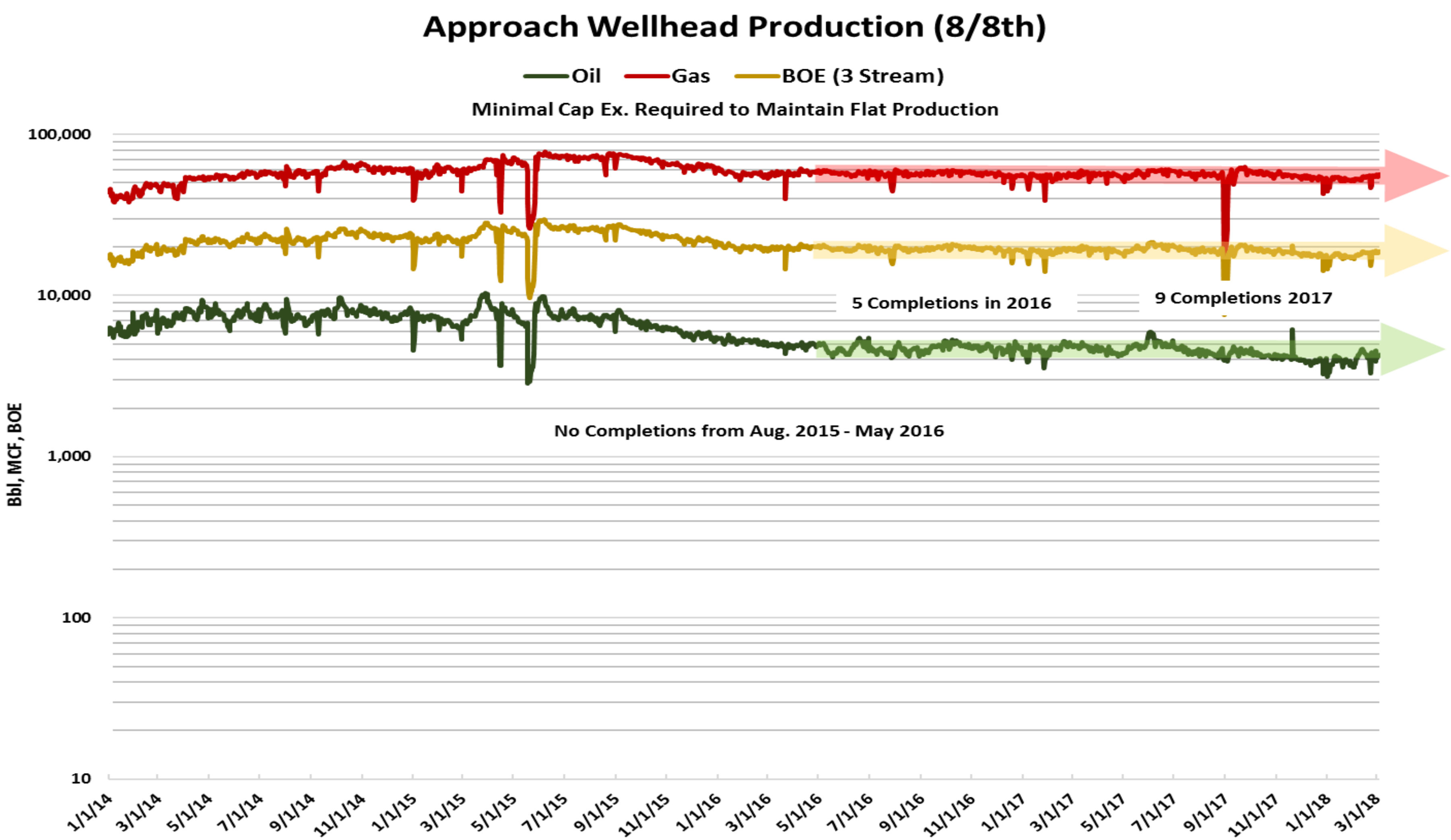
All wells normalized to a 7,500' lateral and for operation down time

2017 Completions

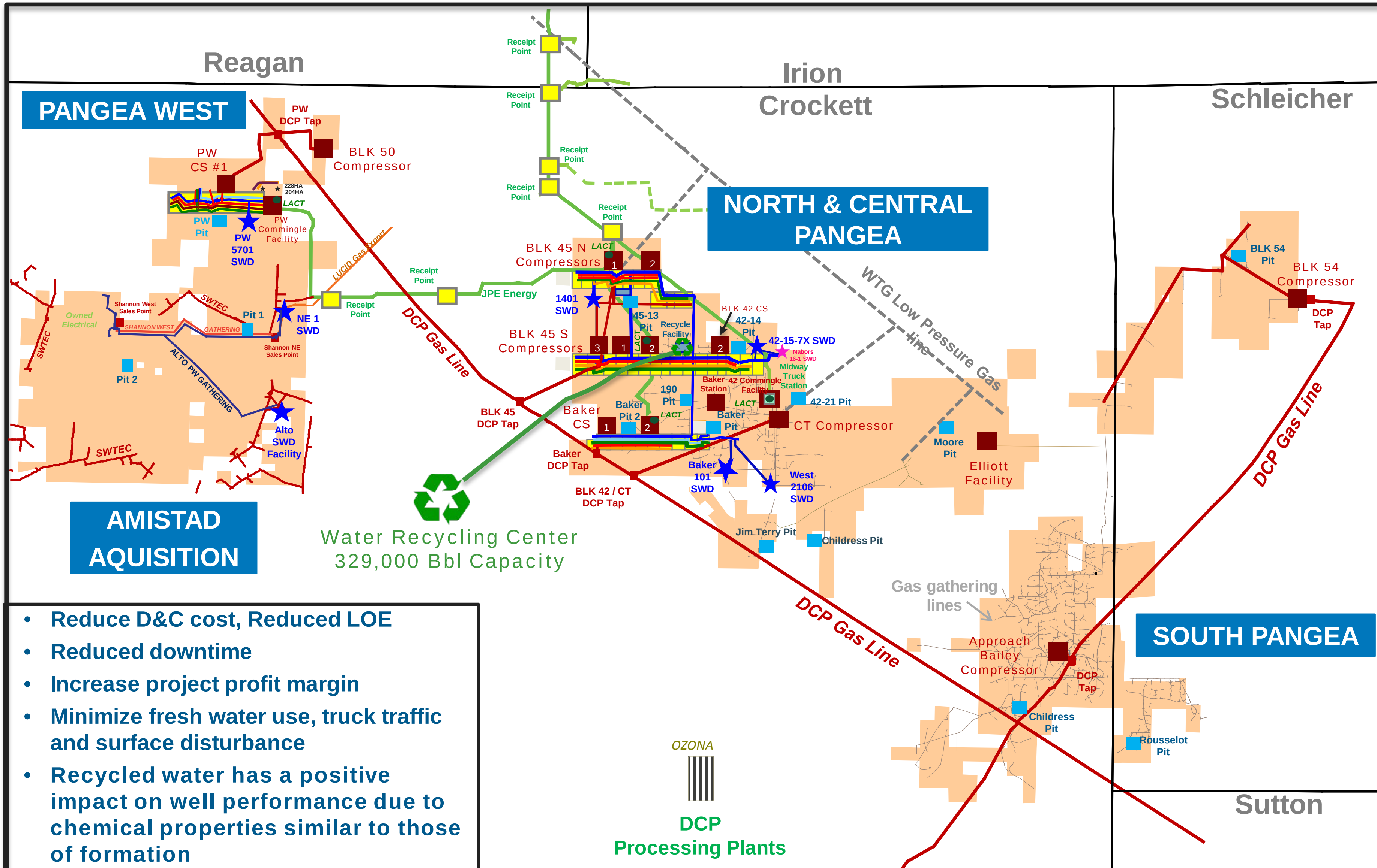


All wells normalized to a 7,500’ lateral and for operational downtime

Low capital intensity required to maintain production



Centralized infrastructure drives capital and operating efficiencies



- Reduce D&C cost, Reduced LOE
- Reduced downtime
- Increase project profit margin
- Minimize fresh water use, truck traffic and surface disturbance
- Recycled water has a positive impact on well performance due to chemical properties similar to those of formation

Full-year 2017 operating and financial highlights

Operating Highlights

- Drilled **13 HZ** wells, completed **9 HZ** wells
- **10 HZ** wells waiting on completion at 12/31/2017
- Total production of **4,232** MBoe (**11.6 MBoe/d**), exceeding the midpoint of annual guidance
- Type curve updated to 700 MBoe EUR, a **37%** improvement from previously type curve
- Proved reserves of **181.5** MMBoe, a **16%** increase over YE 2016
- **$4.23** per Boe lease operating expense, a company record low
- Accretive acquisition - Pangea West bolt-on acquisition, funded by equity, adds production and HBP acreage in highest oil concentration of our core position

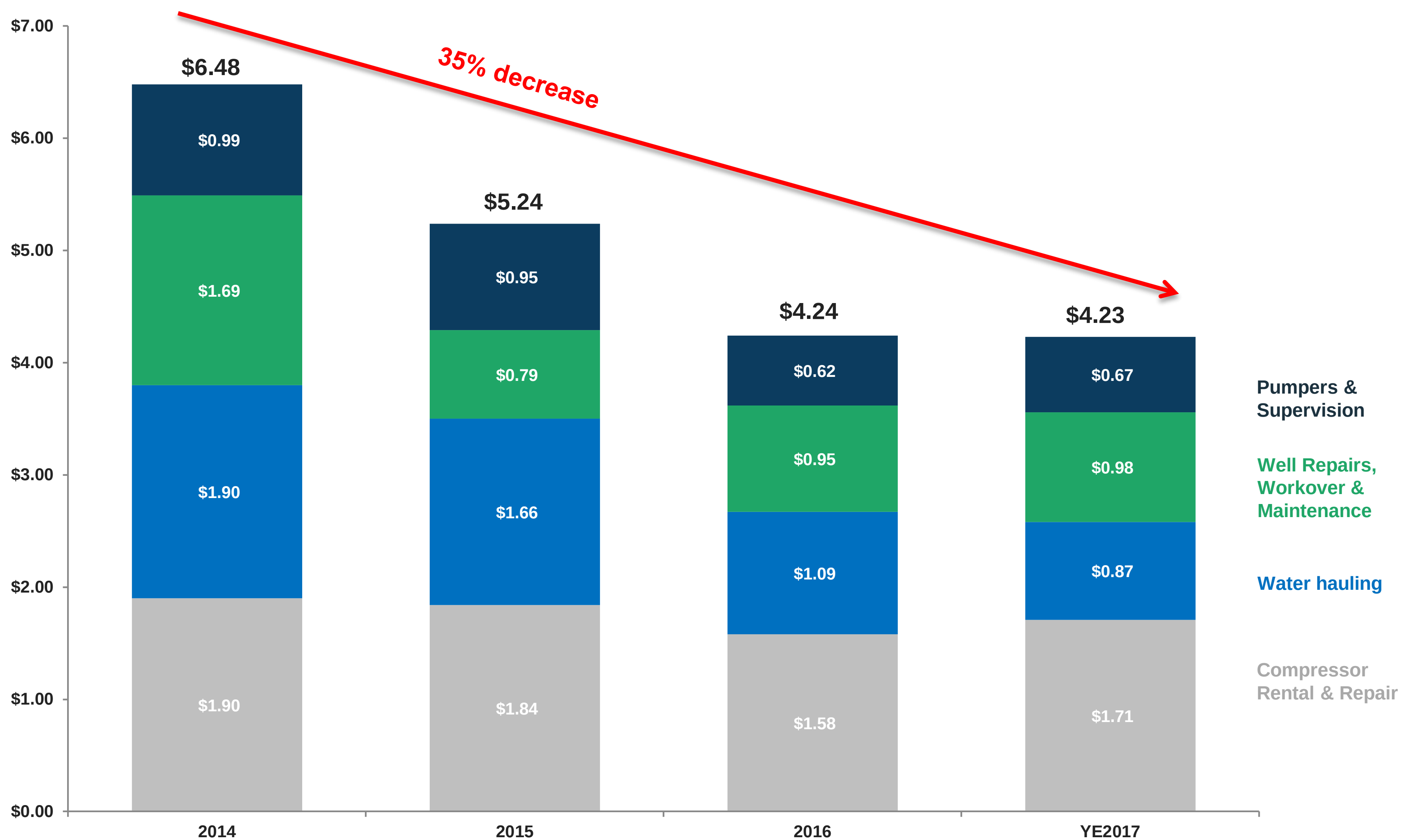
A track record of doing what we say we will do

Financial Highlights

- Strengthened balance sheet and reduced long-term debt by **$127.1** million
- **7%** decrease in LOE YoY
- **44%** increase in operating cash flow, an increase of $11.4 million
- Net loss of $112.4 million or $1.35 per diluted share. Adjusted net loss (non-GAAP) was $29.8 million or $0.36 per share
- **5%** increase in EBITDAX (non-GAAP) over prior year. EBITDAX of $54.8 million
- Extension of credit agreement maturity to 2020, no near term debt maturity, enhances financial flexibility

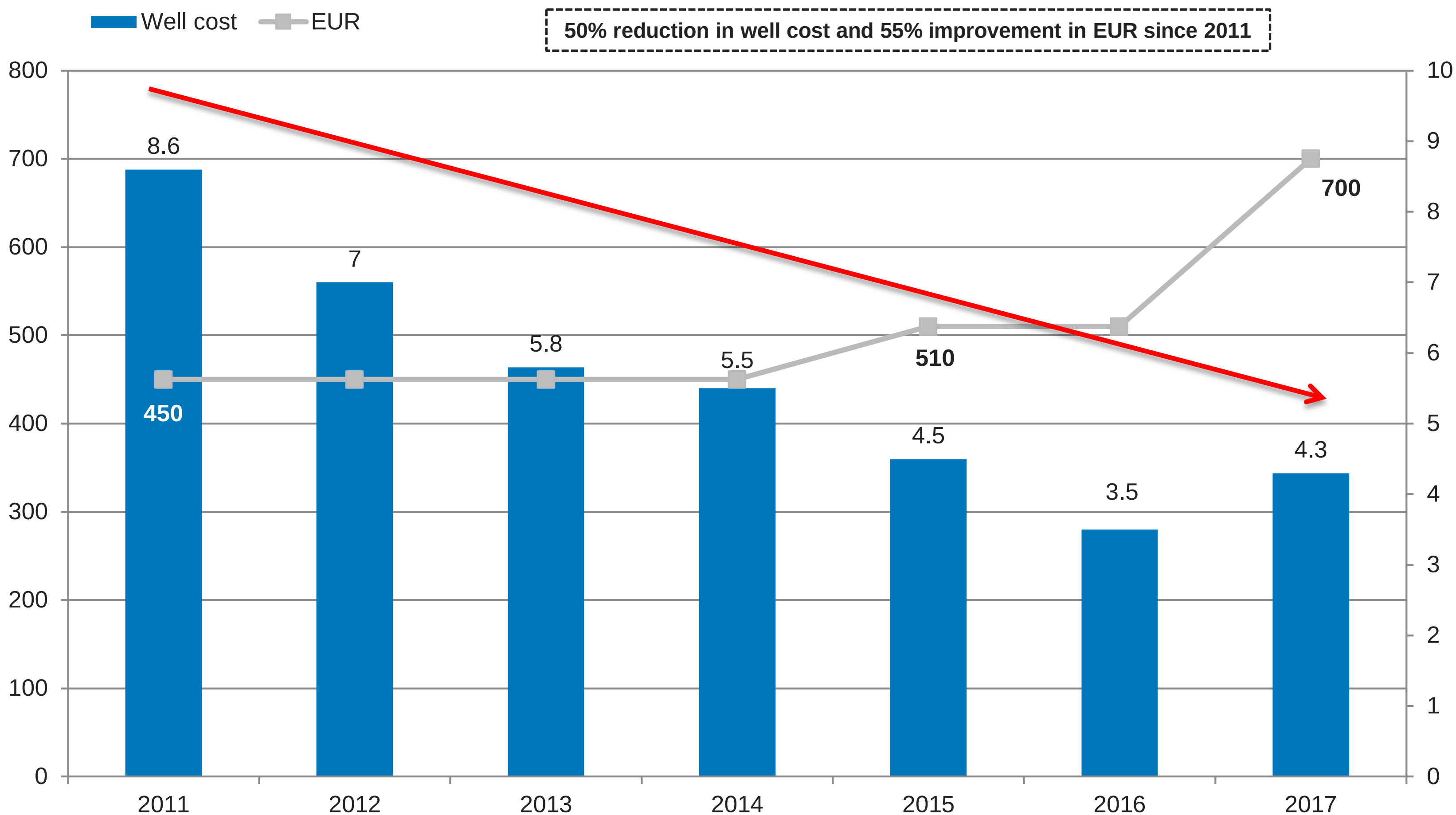
LOE cost reductions driven by water handling infrastructure and field-level operating efficiencies

AREX LOE Historical Track Record ($/Boe)



Approach continues to achieve one of the lowest cost structures in the Permian Basin

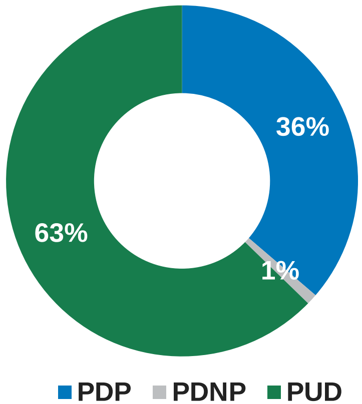
AREX D&C Historical Track Record ($ MM)



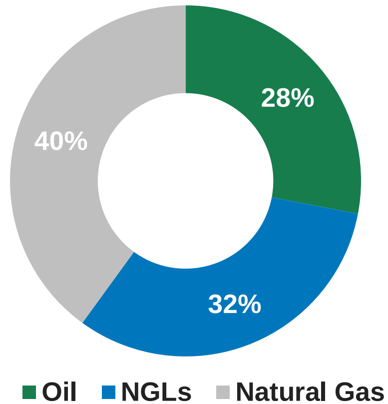
The business is anchored by long-lived, low-cost proved reserve base

- Year-end 2017 proved reserves totaled 181.5 MMBoe
- Reserve replacement ratio of 748% of produced reserves[1]
- Total proved reserves up 16% YoY, proved PV-10 (non-GAAP) of $521 million[2]

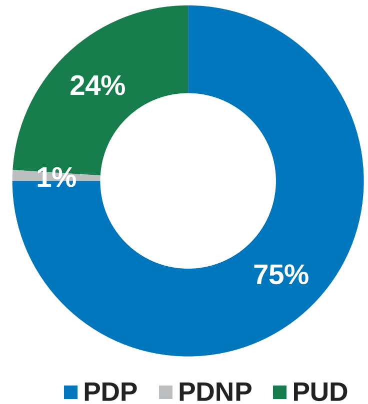
Total Proved Reserves



Reserves by Commodity



Proved PV-10

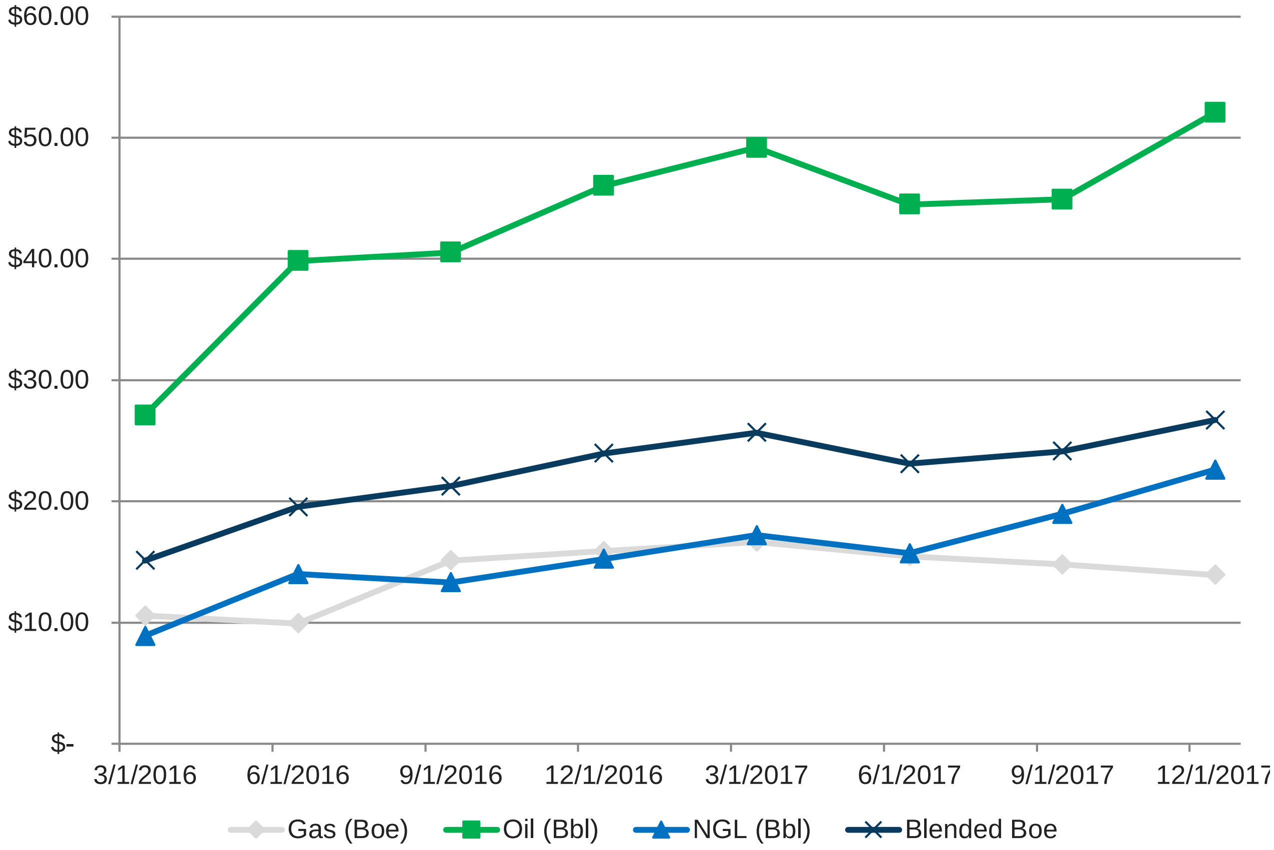


	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf) [3]	Total (MBoe)	PV-10 ($ MM) [2]
PDP	13,661	23,132	175,780	66,089	$394.5
PDNP	192	48	421	310	$1.3
PUD	36,207	34,768	265,027	115,146	$125.2
Total Proved	50,060	57,948	441,228	185,545	$521.0

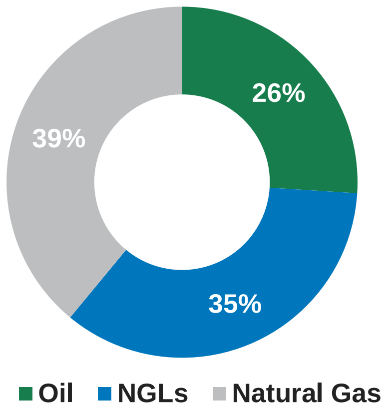
1. Reserve replacement ratio is based on extensions and discoveries of 33,307 Mboe divided by production of 4,452 and includes 1,319 MMcf related to field fuel
2. PV-10 calculated based on the first-of-the-month, 12-month average prices for oil, NGLs and natural gas, of $51.34 per Bbl of oil, $18.67 per Bbl of NGLs and $2.99 per MMBtu of natural gas. See "PV-10 (unaudited)" slide for reconciliation to GAAP measure.
3. The gas reserves contain 57,835 MMcf of gas that will be produced and used as field fuel (primarily for compressors and artificial lifts) before the gas is delivered to a sales point.

AREX is benefiting from commodity price appreciation across all product streams

Change in unhedged realized prices ($ per Boe)



2017 Production Commodity Mix

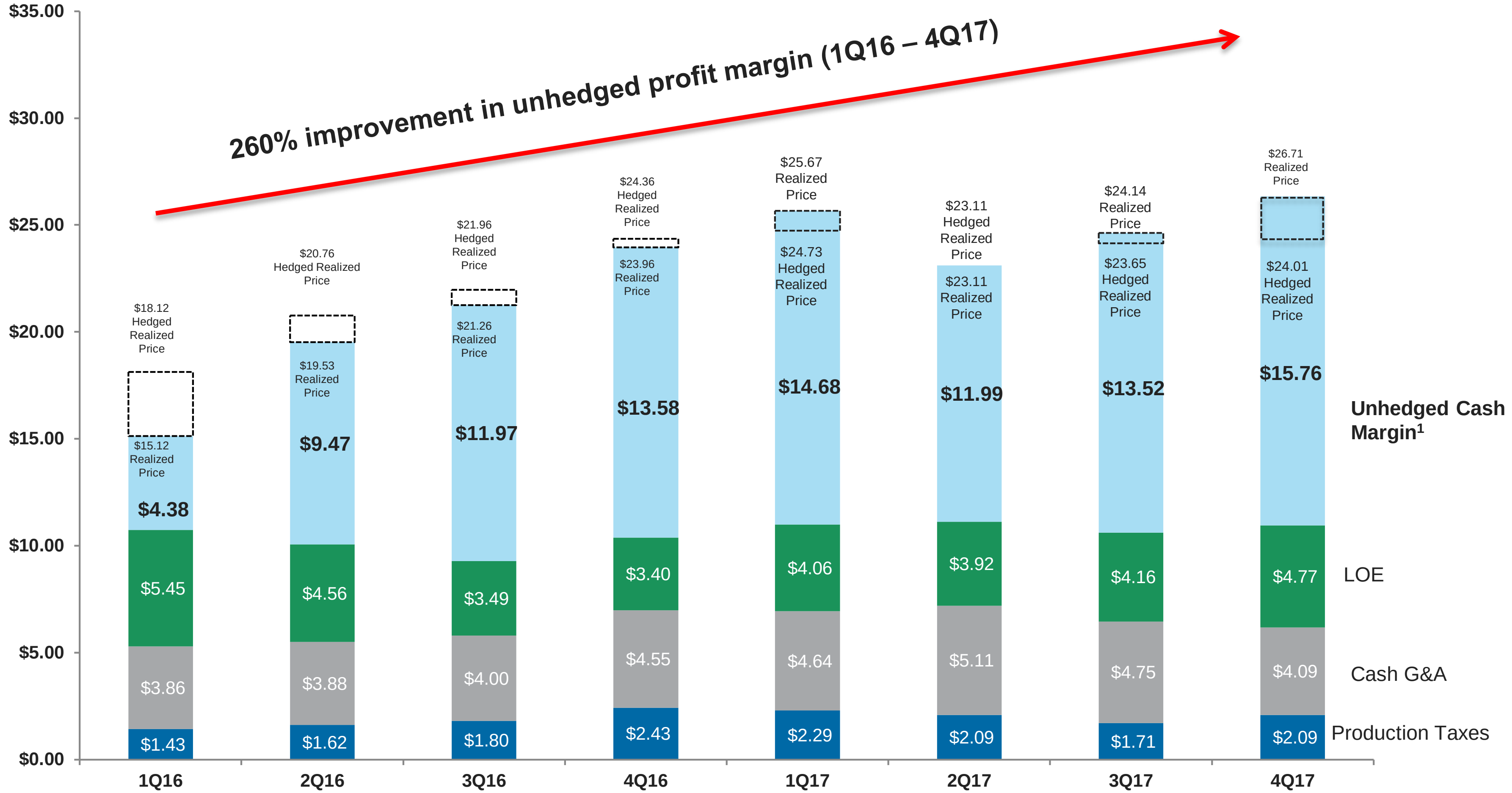


- **2017 unhedged cash margin[1] was $13.97 per Boe**
- **2016 unhedged cash margin[1] was $9.78 per Boe**
- **43% improvement YoY**

1. Defined as unhedged revenue per Boe less LOE, production taxes, and cash G&A per Boe.

Cost reductions and improvement in commodity prices are translating into expanding profit margins

Profit margin per Boe



1. Defined as unhedged revenue per Boe less LOE, production taxes, and cash G&A per Boe.

Balance sheet detail

AREX Liquidity and Capitalization

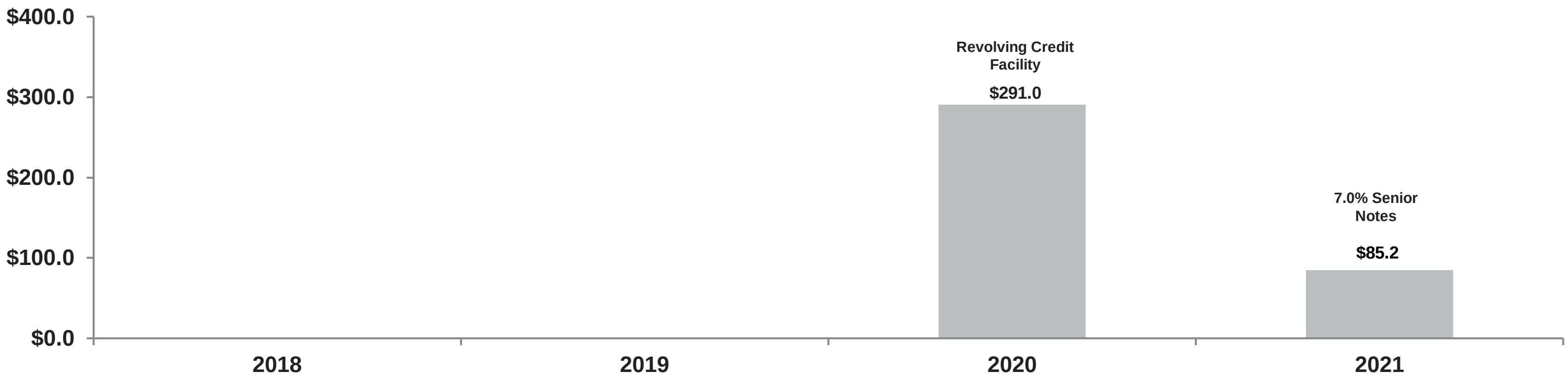
AREX Capitalization as of 12/31/2017 ($ MM)	
Cash	$0.0
Credit Facility	289.3
7.0% Senior Notes due 2021	84.2
Total Long-Term Debt [1]	**$373.5**
Shareholders' Equity	607.4
Total Book Capitalization	**$980.9**

1. Long-term debt is net of debt issuance costs of $2.8 million as of December 31, 2017.

AREX Liquidity as of 12/31/2017 ($MM)	
Borrowing Base	**$325.0**
Cash and Cash Equivalents	0
Borrowings under Credit Facility	(291.0)
Undrawn Letters of Credit	(0.3)
Liquidity	**$33.7**

- Interest coverage ratio of 2.7x, above minimum 1.5x covenant requirement
- Current ratio of 2.1x, above minimum 1.0x covenant requirement
- No near-term debt maturities

AREX Debt Maturity Schedule ($ MM)



Current hedge summary

Commodity and Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
January 2018 – December 2018	Swap	300 Bbls/day	$50.00/Bbl
January 2018 – March 2018	Collar	1,000 Bbls/day	$50.00/Bbl - $55.05/Bbl
January 2018 – June 2018	Collar	500 Bbls/day	$55.00/Bbl - $60.00/Bbl
January 2018 – September 2018	Swap	700 Bbls/day	$60.50/Bbl
April 2018 – September 2018	Swap	800 Bbls/day	$60.50/Bbl
Natural Gas			
January 2018 – December 2018	Swap	200,000 MMBtu/month	$3.085/MMBtu
January 2018 – December 2018	Swap	250,000 MMBtu/month	$3.084/MMBtu
NGLs (C2 - Ethane)			
February 2018 – December 2018	Swap	1,000 Bbls/day	$11.424/Bbl
NGLs (C3 - Propane)			
January 2018 – March 2018	Swap	450 Bbls/day	$30.24/Bbl
February 2018 – December 2018	Swap	600 Bbls/day	$32.991/Bbl
NGLs (IC4 - Isobutane)			
January 2018 – March 2018	Swap	50 Bbls/day	$36.12/Bbl
February 2018 – December 2018	Swap	50 Bbls/day	$38.262/Bbl
NGLs (NC4 - Butane)			
January 2018 – March 2018	Swap	150 Bbls/day	$35.70/Bbl
February 2018 – December 2018	Swap	200 Bbls/day	$38.22/Bbl
NGLs (C5 - Pentane)			
January 2018 – December 2018	Swap	200 Bbls/day	$56.364/Bbl

Production and expense guidance

	Annual Guidance
Production Guidance:	
Oil Production (MBbls)	1,150 – 1,250
NGLs (MBbls)	1,450 – 1,550
Natural Gas (MMcf)	9,600 – 10,200
Total	4,200 – 4,500
Cash operating costs (per Boe):	
Lease operating	$4.50 - $5.50
Production and ad valorem taxes	8.25% of oil and gas revenues
Cash general and administrative (per Boe)	$4.50 - $5.50
Non-cash operating costs (per Boe):	
Non-cash general and administrative	$0.50 - $1.00
Exploration	$0.50 – $1.00
Depletion, depreciation and amortization (per Boe)	$16.00 - $17.00
Capital expenditures ($MM)	~$50 - $70

Summary

- **Concentrated geographic footprint in Permian Basin oil/liquids-rich play**
  - 149,000 net, primarily contiguous acres, 100% operated
  - Stable leasehold, majority of acreage is HBP
  - Balanced commodity mix allows AREX to benefit from commodity price appreciation across all product streams
- **Significant growth potential from Wolfcamp oil shale drilling inventory with ~ 1,350 identified horizontal drilling locations**
  - Multiple, stacked horizontal targets
  - Gross, unrisked resource potential totals ~1BnBoe
- **Large scale gas lift infrastructure systems offer operators more flexibility**
  - Reduces lifting cost
  - Stabilizes well performance with less down time
  - Shallower decline rates realized
  - Minimizes oil production impacts caused by 3rd party plant shut downs
  - Miscible gas flooding and pressure maintenance
- **Strong growth track record at competitive costs**
  - Reserve and production CAGR of 25% and 24% since 2004
  - Low-cost operator with best-in-class D&C and lifting costs
- **New completion design drives better well performance and increases rate of return**
- **Positioned for value growth**

APPROACH RESOURCES

Appendix

Adjusted net loss (unaudited)

The amounts included in the calculation of **adjusted net loss** and **adjusted net loss per diluted share** below were computed in accordance with GAAP. We believe adjusted net loss and adjusted net loss per diluted share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

The following table provides a reconciliation of adjusted net loss to net loss for the three and twelve months ended December 31, 2017 and 2016.

(in thousands, except per-share amounts)	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	**2016**	**2017**	**2016**
Net income (loss)	$ 45,817	$ (13,475)	$ (122,359)	$ (52,243)
Adjustments for certain items:				
Non-cash fair value (gain) loss on derivatives	(1,500)	3,343	(4,097)	11,616
Gain on debt extinguishment	-	-	(5,053)	-
Write-off of debt issuance costs	-	-	-	563
Write-off of deferred tax assets	-	-	139,090	-
Acquisition related costs	110	-	110	-
Tax benefit related to change in federal tax law	(51,939)	-	(51,939)	-
Tax effect and other discrete tax items(1)	1,446	401	4,443	(2,437)
Adjusted net loss	$ (6,066)	$ (9,731)	$ (29,805)	$ (42,501)
Adjusted net loss per diluted share	$ (0.07)	$ (0.23)	$ (0.36)	$ (1.02)

(1) The estimated income tax impacts on adjustments to net income (loss) are computed based upon a statutory rate of 35%, applicable to all periods presented. Additionally, this includes the tax impact of a tax shortfall related to share-based compensation of $1 million, and $1.6 million for the three months ended December 31, 2017, and December 31, 2016, respectively; and $1.3 million and $1.8 million for the years ended December 31, 2017, and December 31, 2016, respectively.

EBITDAX (unaudited)

We define **EBITDAX** as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) non-cash fair value (gain) loss on derivatives, (5) gain on debt extinguishment, (6) write-off of debt issuance costs, (7) interest expense, net, and (8) income tax benefit. EBITDAX is not a measure of net income or cash flow as determined by GAAP. The amounts included in the calculation of EBITDAX were computed in accordance with GAAP. EBITDAX is presented herein and reconciled to the GAAP measure of net income because of its wide acceptance by the investment community as a financial indicator of a company's ability to internally fund development and exploration activities. This measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

The following table provides a reconciliation of EBITDAX to net income (loss) for the three and twelve months ended December 31, 2017 and 2016.

(in thousands, except per-share amounts)	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Net income (loss)	$ 45,817	$ (13,475)	$ (112,359)	$ (52,243)
Exploration	406	685	3,657	3,923
Depletion, depreciation and amortization	16,173	19,402	70,521	79,044
Share-based compensation	1,138	1,998	4,656	6,279
Non-cash fair value (gain) loss on derivatives	(1,500)	3,343	(4,097)	11,616
Gain on debt extinguishment	-	-	(5,053)	-
Write-off of debt issuance costs	-	-	-	563
Interest expense, net	5,370	7,086	21,053	27,259
Income tax (benefit) provision	(53,512)	(3,571)	76,421	(24,418)
EBITDAX	$ 13,892	$ 15,468	$ 54,799	$ 52,023

Unhedged cash margin (unaudited)

We define **unhedged cash margin** as revenue, less cash operating expenses. We define cash operating expenses as operating expenses, excluding (1) exploration expense, (2) depletion, depreciation and amortization expense, and (3) share-based compensation expense. Unhedged cash margin and cash operating expenses are not measures of operating income or cash flows as determined by GAAP. The amounts included in the calculations of unhedged cash margin and cash operating expenses were computed in accordance with GAAP. Unhedged cash margin and cash operating expenses are presented herein and reconciled to the GAAP measures of revenue and operating expenses. We use unhedged cash margin and cash operating expenses as an indicator of the Company's profitability and ability to manage its operating income and cash flows. This measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings and posted on our website.

The following table provides a reconciliation of unhedged cash margin and cash operating expenses to revenues and operating expenses for the three and twelve months ended December 31, 2017 and 2016.

(in thousands, except per Boe amounts)	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2017	2016	2017	2016
Revenues	$ 28,417	$ 26,505	$ 105,349	$ 90,302
Production (Mboe)	1,064	1,106	4,232	4,537
Average realized price (per Boe)	$ 26.71	$ 23.96	$ 24.89	$ 19.90
Operating expenses	$ 29,365	$ 33,564	$ 125,057	$ 135,168
Exploration	(406)	(685)	(3,657)	(3,923)
Depletion, depreciation and amortization	(16,173)	(19,402)	(70,251)	(79,044)
Share-based compensation	(1,138)	(1,998)	(4,656)	(6,279)
Cash operating expenses	$ 11,648	$ 11,479	$ 46,223	$ 45,922
Cash operating expenses (per Boe)	$ 10.95	$ 10.38	$ 10.92	$ 10.12
Unhedged cash margin	$ 16,769	$ 15,026	$ 59,126	$ 44,380
Unhedged cash margin (per Boe)	$ 15.76	$ 13.58	$ 13.97	$ 9.78

PV-10 (unaudited)

The present value of our proved reserves, discounted at 10% ("PV-10"), was estimated at $521 million at December 31, 2017, and was calculated based on the first-of-the-month, twelve-month average prices for oil, NGLs and gas, of $51.34 per Bbl of oil, $18.67 per Bbl of NGLs and $2.99 per MMBtu of natural gas, adjusted for basis differentials, grade and quality.

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating the Company. We believe that PV-10 is a financial measure routinely used and calculated similarly by other companies in the oil and gas industry.

The following table reconciles PV-10 to our standardized measure of discounted future net cash flows, the most directly comparable measure calculated and presented in accordance with GAAP. PV-10 should not be considered as an alternative to the standardized measure as computed under GAAP.

(in millions)		December 31, 2017
PV-10	$	521.0
Less income taxes:		
Undiscounted future income taxes		(323.3)
10% discount factor		263.3
Future discounted income taxes		(60.2)
Standardized measure of discounted future net cash flows	$	461.0

At NYMEX strip pricing at December 31, 2016, PV-10 is $582.2 million. The following table summarizes the NYMEX strip prices at December 31, 2017.

	2018	2019	2020	2021	2022[1]
Oil (per Bbl)	$ 59.55	$ 56.19	$ 53.76	$ 52.29	$ 51.67
Natural Gas (per MMBtu)	$ 2.84	$ 2.81	$ 2.82	$ 2.85	$ 2.89

1. Subsequent year prices were held flat for the remaining lives of the properties
2. NGLs prices per Bbl were estimated at 40% of the oil strip price

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